MAINE'S FUEL COST ADJUSTMENT FOR ELECTRIC RATES

A review and analysis of its role in Maine energy policy

The Public Utilities Commission, in consultation with the State Planning Office and the Public Advocate, shall review the fuel cost adjustment authorized by the Maine Revised Statutes, Title 35-A, section 3101.

A report to the Legislature's Committee on Utilities

by the

Maine Public Utilities Commission

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1. PURPOSE, SCOPE, AND CONTEXT

The purpose of this study is to review the workings of the current law that provides a fuel cost adjustment for electric rates, in order to identify what changes, if any, should be made to that law. In particular, the Legislature has directed us to identify and analyze possible conflicts between the current fuel clause and the statutory mandate for least-cost planning by electric utilities.

This analysis is limited to the effects of the fuel clause at Maine's three largest, investor-owned electric utilities. Smaller electric utilities, with annual revenues below $40 million, are treated differently under the law.

Readers not directly involved in utility management, operations, or regulation might expect to find a discussion of "the fuel clause" to be dull, academic, or inscrutably technical. We hope this report will dispel any such first impressions.

2. DOES THE FUEL CLAUSE CONFLICT WITH LEAST-COST PLANNING?

This review and analysis must include...

1. The extent to which the existing fuel clause adjustment for electric rates impedes the objectives of least-cost planning and demand management as set forth in Title 35-A, chapter 31, subchapters III and VI;

[P&SL 1989, c.106]

2.1 What is "least-cost planning?"

In directing the Public Utilities Commission to conduct this review and analysis, the Legislature cited sections of existing statutes which set forth "the objectives of least-cost planning and demand management." The cited subchapters are known as the Electric Rate Reform Act and the Maine Energy Policy Act of 1988, respectively. In the Electric Rate Reform Act (1977), the Legislature sought "to encourage energy conservation, minimize the need for new electrical generating capacity and minimize costs of electricity to consumers..." The Act directed the Commission to order electric utilities to propose "programs for implementing energy conservation techniques and innovations" and "policies which encourage economic use of fuel and the maximum efficient utilization of natural energy resources indigenous to the State..." In the Maine Energy Policy Act of 1988, the Legislature found "that it is in the best interests of the State to ensure that Maine and its electric utilities pursue a least-cost energy plan." Consistent with the policy expressed in the earlier law to encourage conservation and renewable resources, the 1988 Act directed the Commission to "give preference first to conservation and demand management and then to power purchased from qualifying facilities." The central objective of least-cost planning is to provide the services of electricity at the lowest overall cost to the utility and its ratepayers.

2.2 How does least-cost planning work? What are its goals?

Under current Maine regulations, the planning process begins with a long-term forecast of future demand for electricity, based on expected population growth, economic activity, and future prices for electricity and its substitutes, but initially ignoring the possibility of future utility efforts to help its customers use electricity more efficiently. With a demand forecast, or set of alternative forecasts, in hand, the utility's next step is to estimate the costs of serving those projected loads in all feasible ways, consistent with standards of risk and reliability. The ways considered must include conservation programs, load management, and purchased power, as well as utility-owned generation. In particular, the utility must look for the combination of all such energy resources that would meet projected customer demand at the lowest overall cost.

Since the object of the planning process is to find the least-cost means to serve a given end (the forecast set of customer demands for energy services at the projected prices), it is neutral with respect to the forecast rates of growth or contraction of customer needs for those services. Least-cost planning weighs the generation or purchase of electricity on the same scale with avoiding that power supply through improved end-use efficiency; it is intended to have no inherent bias towards any particular energy resource. In contrast, as explained below in Section 2.4, the incentive effects of the current hybrid, base-and-fuel approach to ratemaking reflect no such neutrality: absent corrective regulatory action, it consistently rewards the utility for successful load-building, and punishes it for successful conservation, regardless of their relative costs.

Fuel clause reform could provide a partial remedy for this current coupling of profits with load growth. In Section 5, we report on an alternative approach to "decoupling" utility profits from load growth through new incentive ratemaking proposals currently before the Commission under Chapter 382 of its rules.

2.3 What is the "fuel clause?" What is its history?

Maine's current "fuel clause" is a procedure for adjusting electric rates between general rate cases to reflect annual changes in the cost of fuel and purchased power. Even without a specific statute, the Commission could provide fuel adjustments, and in fact began to do so for Maine's electric utilities nearly half a century ago, in the 1940s. Three decades later, in 1975, the original fuel clause was enacted in response to the oil crisis. At that time, about 40 percent of the electricity our utilities generated was from oil-fired sources, and oil prices had jumped from the 10 to 15 dollars per barrel range to near 40 dollars per barrel. Because oil was such a large part of the utilities' generation mix, its cost became the dominant element of overall expense. Under such conditions, both shareholders and customers were better served by the reduced risk offered by a mandatory, reconciled fuel adjustment clause. That is no longer the case.

Comparing today's fuel mix with that of 1975, our large electric utilities are today far less dependent upon oil-fired generation, which in 1990 represented one-sixth of CMP's sources, and a smaller proportion for Bangor Hydro-Electric Company and Maine Public Service Company. Oil will take an even smaller share of their combined generation mix in the future. Because oil price exposure risk has been greatly reduced, much of the intended benefit of the clause has also been diminished.

In 1990, Maine's large electric utilities spent nearly half (48.5%) of their total revenues on fuel and purchased power costs, of which 11 percent was for fuel used in generators owned by Maine utilities and 89 percent was for power purchased from other sources, including power generated by Maine Yankee and other jointly-owned nuclear plants, by other utility systems, and by non-utility generators such as paper company cogeneration systems. As a result of the fuel clause, this "fuel" portion of rates differs in a fundamental way from the remaining, "base" portion, which includes all other operating and capital costs. While both are set in each general rate case, only the fuel rate portion of the electric bill is adjusted annually thereafter to reflect actual costs incurred. Fuel rates are set according to cost forecasts, and then reconciled up or down at the end of the period to recover or refund the difference between forecast and actual costs, with interest. Unlike the base portion of rates, in which no such reconciliation occurs, fuel rates closely track actual costs, provided these have been prudently incurred. The fuel clause does not guarantee dollar-for-dollar cost recovery; it may at times be possible to show that a utility could have run its generators or managed its purchases more efficiently. Nevertheless, fuel clause cases typically result in full cost recovery by the utility. Base rates, in contrast, are set with no such retroactive adjustment or expectation that actual costs will be recovered, and remain in effect until the next general rate case, regardless of changed market conditions or management ability.

To illustrate how the current rules work, in a general rate case the Commission might allow an electric utility to charge an average rate of nine cents per kilowatt-hour sold. The nine cents would be the sum of two components: a base (non-fuel) portion of perhaps five cents per kilowatt-hour to cover the "fixed" costs that do not change promptly with changes in output, and a fuel portion of perhaps four cents to capture the fuel and purchased power costs that vary directly with the amount of electricity demanded by the utility's customers. The five cent base portion of the rate remains in effect until the next general rate case, regardless of what happens to the utility's sales, costs, or profits. The four cent fuel portion, in contrast, is reset every year to reflect what the utility has actually spent on fuel and purchased power since the previous adjustment, and what it expects to spend in the coming year.

This hybrid approach to setting rates closely couples utility profits to the number of kilowatt-hours sold, regardless of the cost of making those kilowatt-hours. The variable, four cent fuel portion of the rate assures the utility that it will recover whatever variable costs it actually incurs to make an extra kilowatt-hour while the fixed, five cent base portion adds an extra five cents to sales revenue and thus to bottom-line profit. Conversely, anything that causes a utility to sell one less kilowatt-hour will both deprive it of the five-cent contribution to fixed costs, which is not collected because the sale was not made, and deny the utility the benefit of the four cents of fuel costs avoided by not generating the electricity, since the next fuel clause case will refund to ratepayers, with interest, the actual value of the fuel saved. The peculiar economic incentives created by the current ratemaking rules form the principal focus of this report.

2.4 How might the fuel clause conflict with least-cost planning?

In at least two important ways, the actual operation of the current fuel clause may conflict with our statutory mandate for least-cost planning. First, when rates simply track costs, thrift brings no reward, and waste incurs no penalty. A utility that makes a special effort to reduce line losses in its distribution system, improve fuel economy in its generation plant, or drive a hard bargain for purchased power, has to give back to the customers all of the fuel costs successfully avoided by such efforts. Conversely, inefficient fuel use, or feeble bargaining for purchased power, may drive up costs in ways that are neither clearly imprudent nor easily identified. These higher costs may thus be passed through to the customers, dollar for dollar.

A second kind of conflict with the State's energy policy arises from the way the current rules reward utilities for increased sales of electricity and punish them for decreased sales, whatever the cause. As with any other production process, the costs of making electricity can be separated into fixed costs and variable costs, according to whether the costs vary directly with the level of production. To sell more kilowatt-hours, a utility must burn more fuel or purchase more power, but typically it will not need to pay more interest on its bonds or hire more executives in order to do so, at least in the short run. The short-run variable costs of electricity production are recovered mainly in the fuel portion of rates, with the base portion recovering the fixed costs. As noted above, the special treatment given these variable costs by the fuel clause leads the utility to expect that it will recover whatever added costs it may incur to supply more electricity, should such demand arise. At the same time, the utility will also collect the base portion of the rate for each additional kilowatt-hour sold. With the added sale, the utility gets more money to put towards fixed costs, even though these costs have not increased.

To summarize the preceding paragraph, the fuel portion of rates recovers the added costs of sales growth, and the base portion improves bottom-line earnings. As a result, utility earnings vary directly with the amount of electricity sold: each added sale adds to profit, and each kilowatt-hour *not* sold reduces profit. However the utility chooses to supply the extra electricity, at whatever fuel cost, and regardless of how cheaply its production could be avoided through improved efficiency, cost recovery through the fuel clause rewards the utility for selling more electricity, and punishes it for selling less, other things equal.

Through its rate structure, its conservation and load management programs, and its sales promotion, a utility may influence the amount of electricity its customers use. State energy policy and related regulatory law direct us to meet projected demand for electric service at the lowest overall cost, however the power is generated or avoided, and strongly encourage the development of conservation and load management techniques, and indigenous power supply. To the extent that it creates utility incentives to alter customer demand for energy services, or to provide those services at less than minimum cost, the current interaction of fuel and base rates conflicts with the least-cost principle of Maine energy policy.

In the long run, market forces and the regulatory process itself should both work to limit utility profit and thus counteract at least a portion of any perverse incentive effect. Whether a utility indulges in wasteful production practices or encourages costly (but profitable) growth, the added costs must either be allowed in rates and thus passed on to the utility's customers, or imposed on the utility's owners through regulatory disallowance. The more costs rise and are allowed in rates, the higher the price of electricity. Most customers do have at least some sensitivity to price, and some, particularly in the business sector, may be quite sensitive. A utility that wastefully incurs higher costs and passes them on to its customers as higher rates will eventually suffer at least some loss of sales, and thus reduce base revenue contribution to profit.

Similarly, a utility that encouraged costly sales growth would find sooner or later that some of its profit gain would be offset by the loss of other sales as a result of higher rates, or be cut short by regulators once the excess earnings became apparent. In principle, management might also wish to avoid either excess earnings or excess costs, out of fear that either might attract hostile corporate takeover efforts.

While the product market, the capital market, and rate regulation may each impose some cost discipline and limit the gains from growth in utility sales, these potential offsets are unlikely to be large enough to let us ignore the incentive problems created by the current regulatory process. In the market for electricity, many customers either cannot or do not make large changes in consumption when prices change; typically, changes in electric use resulting from price changes are proportionately smaller than the change in price. In the capital market, aside from a small number of recent corporate battles over companies bankrupted by their investments in nuclear power, very few electric utilities have attracted takeover efforts, and the consolidation of the industry predicted a few years ago by financial analysts has yet to begin. Finally, under current rules regulation itself offers only a partial corrective to the perverse incentives, since the fuel clause rules link profits to sales growth directly and immediately, while any regulatory correction to base rates is only periodic, and not retroactive under current rules.

Several years ago, in Docket Number 87-220, the Public Utilities Commission did change its accounting rules to remove another element of the conflict. Under the traditional fuel revenue accounting practice, a kilowatt-hour sold during the hours of maximum demand for electricity, the "peak period" in which electricity is most costly to produce, also generated more profit for the utility than electricity sold in the less costly, "off-peak" period. The profit incentive thus offered greater rewards for on-peak sales, in direct conflict with both least-cost planning principles and the incentives embodied in the time-of-use pricing encouraged by the Energy Rate Reform Act and Commission policy and practice. The accounting rules now require that the fuel portion of sales revenue be credited mainly to the peak period, and the base portion mainly to off-peak hours. Since profit comes entirely from the base revenue portion, off-peak sales are now more profitable than peak period sales.

In summary, the fuel clause and traditional rate-of-return regulation, under historic cost conditions, encouraged utilities to sell as much electricity as possible, with rewards that were both prompt and long-lived. In the short run, the fuel portion of rates recovered the added costs of sales growth, and the base portion improved bottom-line earnings; each added sale added to profit, and each kilowatt-hour *not* sold reduced profit. In the longer run, traditional regulation and declining costs historically ratified the short-run gains by assuring that investments in anticipation of load growth would also be profitable, whether or not those investments were serving the public need at lowest overall cost. Conflicts arose when the public imposed a least-cost planning standard, or changing cost conditions imposed a risk of competition in power generation. We have already seen how the fuel clause may work against the least-cost planning principle. In the next section, we consider the interplay between the fuel clause and today's power supply conditions.

2.5 Do changing cost conditions and emerging competition alter the incentives implied by the fuel clause?

By allowing full recovery of actual fuel costs, the fuel clause insulates a utility from much of the risk of power supply planning, an advantage that unregulated power generators can only enjoy to the extent that their contracts with the utility provide such insulation. Regulation tends to protect the utility from certain business risks in both the cost and revenue elements of its profit equation.

For example, selling power to a utility under firm contract entails no more risk that the market will disappear, leaving the investment stranded, than that faced by the utility itself, with its regulatory protections. An industrial firm which instead chooses to self-generate carries the full weight of both kinds of planning risk: it may misjudge the fuel markets and find its power generation too costly, or overestimate its own market growth and be left with idle generation capacity. By shifting planning risks to ratepayers through its provision for full, retroactive recovery of purchased power costs, the fuel clause may tend to work against whatever planning discipline emerging competition would otherwise impose. Regulation may succeed in reintroducing that discipline by insisting on sound least-cost planning, with the utility's plan tested by competitive bidding and negotiation.

There are other ways in which the fuel clause could affect planning incentives. A utility that defers new construction as long as possible by running its system closer to the margin will rely more heavily on short-term purchases and load management, and perhaps run its own peaking capacity more hours of the year. In consequence, it will likely find its capital costs lower and its operating and maintenance costs, including fuel, higher. In the absence of a fuel clause, such cost conditions could make load growth temporarily less attractive, especially if the under-recovery of the fuel portion of rates were to become as large as the base portion's contribution to earnings. Conversely, an overbuilt utility that promotes load growth in the hope of using its excess capacity knows that if its promotional efforts succeed too well, they could drive load into the more costly operating regime of capacity scarcity, which without the protection of the fuel clause may impose significant new risk.

With recovery largely assured through the fuel clause, planning loses this discipline and its associated risk: there is both less cause to defer new construction on such grounds as fuel price uncertainty, and less penalty for doing so mistakenly, since in each case it is the ratepayers who are now at risk for the added costs, even in the short run. Similarly, if successful load building efforts raise costs beyond expectations, the fuel clause recovers the short-run excess, and the next round of construction to meet the new load will likely find its way into base rates. Some odd but possible offsets to these load growth incentives may also arise. As one example, by serving to shift the fuel price risk to ratepayers, the fuel clause might also make large, fuel-efficient, base-load plant relatively less attractive to utility planners, since fuel efficiency has less value when this risk is shifted. Similarly, where there is an active inter-utility power market, such as we have developed in New England, the current base-and-fuel hybrid system of ratemaking can reward a utility almost immediately if it can sell, off-system, pieces of its fuel-efficient baseload capacity, and buy pieces of fuel-costly peaking capacity, regardless of the "true" economics of its supply mix.

In summary, changing cost conditions and emerging supply competition have raised some new challenges for utility planners and profit strategists. They have not altered, however, the fundamental linkage between load growth and utility profit that is created by the current system of base-and-fuel ratemaking rules.

2.6 Does the fuel clause treat small utilities differently?

By statute and Commission rule, electric utilities with annual revenues below $40 million are exempt from the specific fuel clause requirements applicable to Maine's three largest investor-owned utilities. This exemption has recognized the value of a simplified fuel clause mechanism for those utilities that purchase all (or virtually all) of their power needs from an investor-owned utility under a contract regulated by the Federal Energy Regulatory Commission (FERC). Since these small utilities have little or no generating equipment under their direct control, the issue of inadequate incentives for managing fuel-related expense rarely, if ever, arises. With this in mind, we have limited the scope of this report to those fuel clause incentives that can or should affect the management practices of Maine's three largest electric utilities: Central Maine Power Company, Bangor Hydro-Electric Company, and Maine Public Service Company.

The conflict identified in Section 2 stems from the way the fuel clause practically assures full recovery of the utility's principal elements of variable cost. Resolving this conflict may require a break in this lock-step linkage between costs and rates. We can think of several ways this might be done.

3.1 Allow PUC flexibility in designing fuel cost recovery rules.

We have shown that the current regulatory rules for recovery of base and fuel revenues have broad, complex implications for electric utility profit incentives. Part of the complexity stems from the interaction of base and fuel revenues, in what we have called the "hybrid approach" to ratemaking. As discussed below, in Section 5, the Commission is currently reviewing proposals for altering the way base rates are set, in order to improve performance incentives and sever the direct link between load growth and profits. Changes in the way utilities recover fuel cost revenues should not be made without thorough review of the likely implications of such changes. The review should include a full airing of the expert opinion, evidence, and argument of all interested parties. The complex and technical nature of the incentive issue, as well as the clear ability of the Commission both to structure such a review and to assure due process, all suggest that investigation and rulemaking by the Commission itself, rather than involving the Legislature in the technical details of fuel revenue recovery, would be the better approach. From this perspective, the existing statutes would be revised to clarify the policy objectives relative to fuel cost recovery and allow the Public Utilities Commission broader discretion to develop specific approaches to implementing that policy.

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3.2 Change the way base (non-fuel) revenues are recovered.

As we have seen, the load-building incentive commonly attributed to the fuel clause actually results from the way fuel cost recovery combines with base rate contributions to profit. Recalling the numerical example of Section 2.2, the extra kilowatt-hour sold will bring in an extra four cents to cover the added fuel costs, and an extra five cents that goes directly and immediately to earnings. The fuel clause assures that the utility will be reimbursed for its actual fuel costs, while the traditional approach to setting base rates assures that the utility gets to keep the five cent contribution to profit. Base rates could be set in a way that allowed the utility to keep a predetermined amount of fixed costs, whatever the level of sales, or sales per customer, thus "decoupling," or breaking the link, between load growth and profit. With no change in the fuel clause, a ratemaking change that permitted a base revenue adjustment of this sort would remove the load-building incentive altogether. As discussed further in Section 5, below, proposals to change base revenue recovery in this way are currently under the Commission's active review.

3.3 Reconcile only a fraction of the actual expense.

If a revised fuel clause were to provide less than perfect hindsight, by reconciling only a part of the difference between fuel costs and fuel rates, a utility would benefit from fuel thrift and suffer from waste, and sales growth would lose some of its appeal. Fuel rates would continue to be set in general rate cases (along with base rates), but only a portion of the difference between forecast and actual fuel costs would be recovered or refunded between rate cases. The rules could permit a gradual transition to such a regime, so that the utility could confidently regain its former ability to operate without cost of fuel adjustments. For example, the timing could be tied to the filing of general rate cases: between the first and second such filings, 80 percent of the fuel cost difference could be reconciled; between the second and third, 60 percent; and so on until, after five general rate cases, there would be no fuel cost adjustment. Or, the rules could permit a continuing partial reconciliation. Alternatively, the extent of the reconciliation could be limited to a prescribed band, such as plus or minus ten percent, around the cost forecast.

In any of these alternatives, utilities would receive a new incentive which is missing under current law. If profits on resold energy are only partially reconciled through the fuel clause, or not reconciled at all, payments for energy sold to other utilities would immediately benefit shareholder earnings. Thus, a utility that sold to other utilities its power surplus created by aggressive conservation and load management could benefit its customers through reduced fuel expense, and its shareholders with increased profit from off-system sales.

3.4 Reconcile only certain components of fuel costs.

Costs have a price component and a quantity component. As a matter of arithmetic, what a utility spends over the course of a year on a particular fuel is the product of the quantity of fuel burned and the average price paid per unit of fuel consumed. The quantity of fuel burned at a particular generator depends on how much electricity was needed by the system, how often the generator in question was called on to supply that need, and how efficiently the fuel was converted to electricity. The average price paid depends on the type or mix of fuel required or chosen, price movements in the relevant fuel markets, and the timing and competitiveness of utility purchases. Typically, the utility has less control over the price paid for fuel traded on a world market than it has over the quantity consumed at its generating stations. Where possible, incentives should be targeted to those elements of cost over which the utility has most control. If we are not ready to wean our utilities entirely from the fuel clause, this logic suggests changing the rules to remove the adjustment for fuel cost changes associated with changes in the amount of fuel burned, whether from changes in sales growth or fuel efficiency, but continuing to adjust cost recovery for changes in the prices paid for fuels and purchased power.

4. HOW WOULD FUEL CLAUSE CHANGES AFFECT MAINE'S ECONOMIC DEVELOPMENT?

This review and analysis must include...

3. The extent to which economic development in the State may be assisted by means of more meaningful incentives;

[P&SL 1989, c.106]

The central objective of least-cost planning by electric utilities is to provide the services of electricity at lowest overall cost to the utility and its customers. To the extent this objective is achieved, these services will consume fewer scarce resources, and firms depending on electricity will face lower costs and an improved competitive position. Changing the fuel clause to reduce or remove its conflict with least-cost planning could thus enhance economic development in the State.

A second way in which other elements of the Maine economy might be affected by changes to the fuel clause is through increased off-system sales stimulated by the new opportunity to retain possible profits from such sales, as discussed in Section 3.2, above.

5. HOW DOES THE INCENTIVE RULEMAKING RELATE TO FUEL CLAUSE CHANGES?

> *This review and analysis must include...*
>
> *4. The status of the commission's pending rulemaking on regulatory reform and incentives and its relation to the fuel cost adjustment issues in subsection 1.*
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> [P&SL 1989, c.106]

In adopting Chapter 382 of its rules, the Commission set in motion a means to solicit and review proposals for certain ratemaking or accounting changes. These changes seek to reduce or remove the current conflict between the regulatory goal of least-cost planning and the business goal of maximum profit. The Chapter 382 proceedings are designed to generate workable proposals for mechanisms that both insulate utility profits from load growth and adjust profits in proportion to some measure of cost performance, thus creating broader incentives for improved efficiency.

As noted above, it is the base revenue portion of an added sale that generates profit, which is then ratified, so to speak, by the fuel clause. With base rates fixed until the next rate case, and not adjusted retroactively, utilities get to keep the base revenue portion of every kilowatt-hour sold. The fuel clause assures that the added fuel cost will be recovered later and thus will not diminish the base revenue profit. Absent the base revenue contribution, the added sale would carry no profit incentive, even with the fuel clause, and would reduce profits without it. Thus, under the current system for setting base revenues, profits would be linked to sales growth even without the fuel clause, so long as the base revenue portion of the rate (e.g., five cents) were larger than the fuel revenue portion (e.g., four cents).

From this perspective, it becomes apparent that the more direct and complete way to insulate utility profits from load growth is to unhook base revenues, rather than fuel revenues, from the level of sales. This decoupling is one of the major objectives of the Chapter 382 proceedings. The current status of these efforts by each of the three utilities is described below. All three took part in a public discussion of an earlier draft of this fuel clause report, and filed detailed written comments.

5.1 Central Maine Power Company.

On August 1, 1990, Central Maine Power Company filed with the Commission a revised Chapter 382 proposal, describing an incentive regulation approach that it would be willing to adopt. In its August 21, 1990 Order in Docket No. 90-085, the Commission agreed that the approach outlined by CMP held some promise of meeting the requirements of the rule, and directed the parties to CMP's then-current base rate case, Docket No. 90-076, to apply its principles and incorporate its design as part of the specific rate requests in that proceeding, beginning at the rebuttal phase. On September 21, 1990, CMP filed a more detailed description of its "Shared Benefits Incentive Program." Following extensive meetings and negotiations, the interested parties filed a joint proposal in late December. A hearing was held, and the matter is scheduled for Commission action in April.

5.2 Bangor Hydro-Electric Company

Analysis by PUC staff of the August, 1989, Chapter 382 proposal submitted by Bangor Hydro-Electric Company concluded that the proposal did not satisfy the requirements of the rule, but could be revised to do so. On January 18, 1991, the Commission opened a formal investigation of the Bangor proposal, under Docket No. 90-310. A schedule for further proceedings has not yet been established.

5.3 Maine Public Service Company

Maine Public Service Company commented on the proposed Chapter 382 rule during the rulemaking proceeding, but has not submitted a formal proposal.

6. CONCLUSION.

This section reviews the key points of the preceding analysis, suggests some cautions, and concludes with a recommendation for modest changes to existing law, pending the outcome of the current Chapter 382 proceedings.

6.1 The case for reform, in brief.

Under historic cost conditions, the fuel clause and traditional rate-of-return regulation work hand in hand to encourage utilities to sell as much electricity as possible, with rewards that are both prompt and long-lived. The fuel portion of rates recovers the added costs of sales growth, and the base portion improves bottom-line earnings; each added sale adds to profit, and each kilowatt-hour *not* sold reduces profit. Conflicts arise when the public imposes a least-cost planning standard, or changing cost conditions impose a risk of competition in power generation. Our current system, which links base revenues to sales and fuel revenues to actual costs, works against both the principle and practice of least-cost planning: it blindly rewards load growth, and, by shifting risks to ratepayers through purchased power contracts, dulls whatever planning discipline emerging competition would otherwise impose.

The least-cost planning principle tells us to weigh the generation or purchase of electricity on the same scale with avoiding that power supply through improved end-use efficiency; it has no inherent bias towards any particular energy resource. The current hybrid approach to base and fuel ratemaking, in contrast, reflects no such neutrality: absent market or regulatory correction, it consistently rewards the utility for successful load-building and inefficient fuel use, and punishes it for successful conservation and maintenance, regardless of their relative costs.

6.2 Some notable cautions.

The fuel clause mechanism effectively insulates the utility from variations in fuel prices, purchased power costs, and the fuel costs consequences of unanticipated changes in sales of electricity. Reducing or removing this protection could make utility earnings less predictable, especially during periods when oil prices are unstable. Changes in its pattern of earnings could, in turn, raise the utility's borrowing cost or otherwise alter its cost of capital, and thus make their way into rates in one way or another. Should the insulation from such cost changes be counted as a benefit of the current fuel clause? The answer is not immediately obvious; it hinges on whether the cost differences reflect changes in the real use of productive resources, or simply a transfer of benefits from one group to another.

In Docket No. 87-220, the Commission changed the way Central Maine Power Company and Bangor Hydro-Electric Company account for the fuel portion of sales revenues. Before this accounting change was adopted, electricity sales during peak periods, when production is most costly, were also most profitable, thus rewarding the utility for increased load at peak times and penalizing it for load management programs that succeed in shifting electric use to less costly periods. The purpose of the accounting change was to reverse this incentive, so that more profit would be booked from off-peak sales, and less from peak periods. The current effort under Chapter 382 to solicit utility proposals for overhauling the incentive structure simply extends and generalizes the logic of the earlier reform of fuel revenue accounting. Although its actual impact is hard to measure, the accounting change appears to be working as intended; utility pursuit of load shifting programs such as residential water heater cycling and industrial interruptible load has been relatively vigorous. While the accounting change does not correct the overall bias toward sales growth, it does shift its focus to the less costly periods. Revisions to the fuel clause should be carefully designed to preserve this clear benefit, either in the fuel clause itself or as part of a larger overhaul of incentive structures under Chapter 382.

By providing more or less assured recovery of actual fuel costs, the current fuel clause system probably reduces the frequency of utility filings for general rate increases. Under conditions of unstable fuel prices, eliminating the fuel clause would probably bring us, in exchange, general rate cases every year. Such a regime would both raise the cost of regulation and erode at least part of the incentive benefit that might otherwise be achieved, since the added costs to serve new load, while no longer fully recovered through the fuel clause, could be captured within a year by a general rate increase. Meanwhile, the other growth incentives embodied in traditional regulation would remain in place.

6.3 Recommendations and proposed legislation.

Traditional regulation of electric utilities encourages load growth, even when such growth is uneconomic. Abolishing or reforming the fuel clause could reduce but not eliminate this load-building bias, and could also impose some offsetting costs. We therefore recommended a cautious approach to fuel clause reform, as follows:

6.3.1 Allow PUC flexibility in designing fuel cost recovery rules.

The complex and technical nature of the incentive issue, as well as the clear ability of the Commission both to structure such a review and to assure due process, all suggest that investigation and rulemaking by the Commission itself, rather the Legislature, would be the better approach. The existing statutes should be revised to clarify their policy objectives relative to fuel cost recovery and to allow the Public Utilities Commission the flexibility to develop specific approaches to implementing that policy.

6.3.2 Change the way base (non-fuel) revenues are recovered.

As we have seen, the load-building incentive commonly attributed to the fuel clause actually results from the way fuel cost recovery combines with base rate contributions to profit. Base rates could be set in a way that allowed the utility to keep a predetermined amount of fixed costs, whatever the level of sales, or sales per customer, thus "decoupling," or breaking the link, between load growth and profit. With no change in the fuel clause, a ratemaking change that permitted a base revenue adjustment of this sort would remove the load-building incentive altogether. Proposals to change base revenue recovery in this way are currently under the Commission's active review. Some enabling legislation may be also be desirable.

6.3.3 Insist on sound least-cost planning.

By insisting on sound least-cost planning, with the utility's plan tested and proved through competitive bidding and negotiation, determined regulation may succeed in reintroducing market-like planning discipline.